

Costs of Liquid Fuels from Oil Shale

Harry Perry ^{1/}

U.S. Department of the Interior
18th and C Streets, N.W.
Washington, D.C. 20240

I. Introduction

The immense size of the oil shale deposits of Colorado, Utah, and Wyoming with their promise of riches have been a constant challenge to the scientist, the engineer, the entrepreneur and, indeed, the entire petroleum industry. The shortage of oil during World War I provided a stimulus for investors to try to bring this resource to the point of commercial utilization. By the early 1920's ownership of the land had been complicated by the terms of the Mineral Leasing Act of 1920, which changed the method by which the lands could be alienated. In addition there was no indication that the processes then under consideration were technically or economically attractive, and the establishment of an oil shale industry did not occur at that time. Subsequently, the discoveries of very large, low cost reserves of oil in East Texas delayed the possible development of the resource for many years.

Legal problems associated with title to the lands have been an integral part of the history of the oil shale deposits. Concern over the disputes about ownership led to the withdrawal of the lands in 1930 for oil shale leasing. The withdrawal has continued to the present except for three test leases which were offered in December 1968. In 1964, the Department of the Interior instituted some test cases against the pre-1920 claims which are still under consideration. Other actions were taken to test the validity of post-1920 claims and as a result, the Department of the Interior has made great strides in resolving the title clearance issues. Their resolution is indispensable to the orderly development of the resource.

II. The Need for Synthetics

As shown in Table I, demand for energy is expected to continue to rise, as it has in the past, so that BTU consumption in the U.S. may increase about 260 percent between 1968 and the year 2000. In absolute terms this is an increase in demand of an oil equivalent of 11.0 billion to 28.7 billion barrels per year. Energy use in the form of liquid fuels is expected to increase about 190 percent over this same period or an increase of from 4.9 billion barrels in 1968 to 9.6 billion barrels in 2000. Most of the demand for petroleum will continue to be used in the transportation sector (autos, trucks, buses, airplanes); this sector is dominated by liquid fuels which supplied over 95 percent of the energy consumed in 1968.

These predictions were made during a time when, while there was an awareness that air pollution and other environmental controls could have an impact on patterns of energy consumption, the potential magnitude of the new environmental standards could not be factored into the projections. For example, recent indications that leaded gasoline may no longer be an acceptable fuel have opened up new requirements and opportunities for meeting the demands of the transportation sector. Lead-free gasoline can be produced using present technology but this requires a higher percentage of aromatics and isoparaffins if octane ratings are to be maintained. To meet any wide-spread demand for lead-free gasoline would require that the petroleum industry install an enormous amount of additional processing units, particularly for reforming and alkylation. The extra costs of lead-free gasoline have been estimated to be 2 cents per gallon or a total cost of 2 billion dollars a year in the U.S.

^{1/} Mineral Resources Research Advisor, Assistant Secretary of Mineral Resources Office

The need to tool up to produce modified designs of engines and fuels could induce industry to look seriously at other automotive power plants such as gas turbines, steam engines, Wankel engines, combined gasoline-natural gas engines or electric vehicles.

Environmental considerations are rapidly creating a large new demand for a low sulfur residual oil to be used at electric generating stations and industrial plants. This fuel would replace coal which could not meet air pollution standards for sulfur oxide emissions. In PAD District I, where under present oil import regulations, unlimited amounts of residual oil imports are permitted, imported low sulfur residual has already replaced significant amounts of high sulfur coal. Recently, approval was given for importation of low sulfur residual oil into Chicago. If oil import regulations are changed (specific recommendations for change have been made to the President by a Cabinet Level Study Group) this trend could be greatly accelerated.

As previously noted, the combined effects of these two developments or others still to come, on total liquid fuel demand are still too recent to permit modification at this time of the projections shown in Table I. However, the effects of these and other changes caused by the establishment of future environmental standards will affect the patterns of demand and supply. On the other hand, all the fuel resources at our disposal will have to be used in some form if the tremendous demand for energy that has been predicted actually occurs. The fuel forms may have to be modified to meet other standards placed on them but the total energy demand could not be met if oil (or heat units derived from it) were not used in about the quantities shown in Table I.

Synthetics, whether from oil shale, tar sands or coal, will only be used when they can compete economically with other energy sources or with crude petroleum under the public policies that prevail at any given time. The ability of synthetics to enter the market will obviously depend on how much crude oil is found. This in turn is a function of the oil import program that eventually emerges, the incentive for investment in exploration, and the size of the Alaskan discovery coupled with the cost of delivering that crude oil to markets. As shown in Figure 1, the declining reserves to production ratio that started in the early 1960's is expected to continue and this should provide an incentive for the oil industry to look to other sources of supply.

III. Oil Shale Development--Non-Technologic Factors

The development of the oil shale resource is dependent on the existence of a technically feasible process that is economic under the conditions prevailing that determine the price of crude oil. The major non-technical factors that affect the price of crude oil with which shale oil would compete are the oil import program (how much can be imported and under what conditions), the depletion allowance for oil, state prorationing practices, and Federal leasing policies both on-shore and on the Outer Continental Shelf--particularly new stringent safety regulations which may increase costs.

Other important factors that will affect the timing and the rate at which oil shale processing becomes commercial are the rate at which the clouded titles on most of the publicly owned lands can be removed; any modifications of the terms of the Mineral Leasing Act of 1920 under which the oil shale lands are leased by the Government, which of the different bidding procedures the Government elects to use, and the terms and provisions of the lease. Certain types of shale deposits are almost entirely in Government ownership. If a technology is developed for using them that is more economic than for the deposits in private hands, then the Government would control entirely by its lease offerings the rate and time when an oil shale industry would emerge.

In addition, actions taken by state and local governments could either help or deter an oil shale development, the large capital requirements to attain economies of scale will limit the number of possible participants in the industry, and the institutional practices of the oil industry will make it difficult for those not

already in the oil business to enter an oil shale industry. Moreover, the relative costs, as well as other factors, of producing synthetics from oil shale compared to coal will also be of importance in determining the onset of an oil shale industry.

IV. Status of Oil Shale Technology

There are basically two ways to produce a crude shale oil from oil shale. In the first, the oil shale is mined and then retorted where, by the application of heat, the crude shale oil is distilled from the oil shale. In the second, wells are drilled from the surface to the oil shale deposit, the permeability of the oil shale is increased by some method, and the shale oil distilled from the deposit by an in situ application of heat.

1. Mining

Underground mining, using the room and pillar method, was extensively investigated by the Bureau of Mines and Union Oil Company during the 1950's and by the Colony Group in the 1960's. These experiments concentrated on developing methods to extract the 70-foot thick rich Mahogany ledge deposit which is found in many parts of the Piceance Basin in Colorado. Feasible methods for underground mining have been demonstrated although there are still potentials for further cost reduction.

Open pit mining of oil shale should present no problems that have not been solved in mining for other mineral resources by this method. However, there has been no experimental testing of open pit mining in the oil shale resource. The costs associated with this method of mining will depend on the thickness and grade of shale and on the geologic conditions--the thickness of the overburden and its physical characteristics. It has been suggested that appreciably lower costs than those associated with underground mining operations can be anticipated in locations where a rich deposit of shale outcrops to the surface. In such a case, there would be little investment required before commercial amounts of shale could be extracted and used and costs should be low.

2. Retorting

In the retorting of mined shale a large number of processes have been proposed, but in the last decade only three have been tested extensively enough to be considered for commercial development at this time. These are the Bureau of Mines gas combustion retort, the Union Oil Company retort and Oil Shale Corp., (TOSCO) process. The Bureau of Mines and Union Oil Company retorts, both of which are internal-combustion types, are based on similar process principles with the major difference being the direction of flow of the shale and air. The TOSCO process consists of a retorting kiln in which finely crushed oil shale is heated to retorting temperature by heat exchange with hot ceramic balls heated in another vessel. It is claimed that more shale oil is recovered per ton of oil shale treated and that the shale oil is of better quality than that produced in the retorts using direct heating and a larger sized oil shale feed. However, the economics of the production of shale oil estimated in this paper are based on results obtained in the Bureau of Mines gas combustion retort since insufficient published data were available for the other two processes to make engineering estimates of costs of shale oil produced by them.

3. In Situ Retorting

In situ retorting of shale using non-nuclear techniques for increasing the permeability of the oil shale has been tested by several companies and by the Bureau of Mines. Methods used in recent experiments by the Bureau of Mines to increase the permeability of the oil shale included electrolinking, hydraulic fracturing and explosive fracturing. Electrolinking followed by hydraulic fracturing did not increase permeability appreciably. Explosive fracturing following hydraulic fracturing

improved the permeability by a factor of 5. In a series of field tests, 11 new wells were drilled in an area where 4 previous wells had been drilled. The center well was ignited in an attempt to retort a 20-foot thick (22 gallons per ton) section of the oil shale located 68 to 88 feet below the surface. After six weeks of operation, the process produced 190 barrels of a medium viscosity low pour point shale oil. Later tests of the deposit indicated that only a 5-foot section of the 20-foot shale bed had been retorted. Although there remain several important unsolved problems, such as better utilization of the shale, improved control of the combustion front, and the use of wider spaced wells with reasonable pressure drop, these in situ tests have demonstrated a much higher degree of technical feasibility for the process than had previously been demonstrated.

The use of a nuclear device, exploded underground to create a chimney filled with broken oil shale which could then be retorted in place, has been under serious consideration for over 10 years in a program to be sponsored jointly by industry and Government.

Extensive preliminary engineering studies have been made to estimate (1) the size of the chimney from a given sized device detonated in oil shale, (2) the size distribution of the broken shale, and (3) the amount of shale oil that would be recovered from a single chimney.

To determine the amount of shale oil that could be recovered from a mass of broken rock containing the wide size distribution that might result in a nuclear made chimney, a 175-ton retort was constructed to simulate those conditions. The retort was filled with oil shale ranging in size from fines to one large piece weighing 7500 pounds. In a single 24-day experiment, an oil yield of approximately 60% of the Fischer assay was obtained. Operation of the retort was smooth with uniform temperature distribution across the bed and with low pressure drop. The characteristics of the shale oil were a little better than those obtained from above-ground retorting in the gas combustion retort having a somewhat lower pour point and viscosity and a lower nitrogen content.

Additional tests will be required to firm up what was learned in this single experiment but there is every indication that higher recoveries and better quality of product can be produced when the optimum operating conditions are established.

V. The Economics of the Oil Shale Production

In the Department of the Interior report on oil shale issued in May 1968, ^{1/} shale oil production was estimated for 5 different mining systems each using (1) a 45-foot diameter retort, (2) a 60-foot diameter retort, and (3) a second generation retort using improved technology. The capital investment, annual operating costs and cost per barrel for each of these 15 conditions are shown on Table 2.

Using a 12 percent discounted cash flow and with no value assigned to the shale resource the cost per barrel (after a 61 cents credit for by-products) is shown in Figure 2 for 6 sets of conditions. The two plants for 1972 were identical except for oil shale quality. Increasing the quality of that shale from 30 to 42 gallons per ton decreased costs 72 cents per barrel. The 1976 case, in addition to using a larger diameter retort than was used for the 1972 case, compared the effect of open pit to room and pillar mining. It also tested the effect of increasing plant size by four fold. An increase from 62,000 to 250,000 barrels per day decreased costs 27 cents per barrel.

Since these calculations were made, four important factors that significantly affect the economics have occurred. These are (1) the by-product credit of 61 cents per barrel is believed to be too high and a more realistic value is probably 41 cents per barrel for all cases except the second generation plant where 77 cents is used in these new calculations, (2) capital and operating costs of new plants have

^{1/} Prospects for Oil Shale Development--Colorado, Utah, and Wyoming, Department of the Interior, May 1968

increased significantly over the 1966 costs used in the earlier report, (3) the point at which the depletion allowance is applied has been changed by law from 15 percent on the oil shale to 15 percent on the crude shale oil, and (4) the value of the semi-refined shale oil in Colorado has increased about 25 cents per barrel.

Table 3 compares the 1966 and 1969 conditions for four different types of retorts and mining systems. Capital investment costs increased about 10 percent during this period. Annual operating costs increased from a low of 13 percent for the improved first generation retort and improved room and pillar mining system (case 3) to a high of 25 percent for the first generation retort with conventional room and pillar mining (case 1).

The decreased value assigned to by-product credits of 41 cents in the 1969 study compared to 61 cents assigned in 1966 was more than balanced by the increased value of the semi-refined crude oil in Colorado. The net market value of the products resulted in an increase of 5 cents per barrel to \$3.74. On the other hand, even after the tax benefits that accrue from changing the point at which the depletion allowance may be credited, and this is approximately 10 cents per barrel, the increased capital and operating costs raised the cost of producing semi-refined crude oil from a low of 12 cents (case 3) to a high of 38 cents per barrel (case 1). As a result, the discount rate (at zero resource value) that equates cash flow to cost dropped from 13 to 9 percent for case 1 and from 22 to 20 percent for case 4 with intermediate values for cases 2 and 3.

In situ retorting costs for 1966 for both nuclear and conventional were shown in the 1968 oil shale report. For the most favorable case, i.e., nuclear in situ with a 70 percent recovery efficiency of the oil and air pressure for retorting at 50 p.s.i., costs were estimated at \$2.98 per barrel of shale oil. The 1969 costs increased 45 cents for a total cost of \$3.43 per barrel. This is a larger increase than for any of the cases shown in Table 3, and results in part from the method by which the depletion allowance was applied in the 1966 estimate. Since no oil shale is mined during in situ retorting it was not possible to take a 15 percent depletion on the oil shale. As a result, it was taken on the shale oil. Consequently, in the 1969 estimate there was no additional reduction as a result of the change in depletion allowance from oil shale to shale oil.

The 1966 estimate included costs for prevention of air and water pollution from both the retorting and refining operations. It also included costs for purchase of land and for other costs involved in storing spent shale in a manner which would prevent air pollution from the dried spent shale and water pollution from the leaching of the spent shale. However, the costs did not involve replacing as much of the spent shale as possible in either underground or open pit mines. While such costs will vary widely from lease to lease depending on other factors that determine plant location with respect to the mine (water availability, access to the property, suitable areas for the balance of waste disposal, relative elevation of the plant and mine) an average value of about 20 cents per barrel has been estimated over previous estimates for waste disposal.

Another limitation of these estimates (both the 1966 and the 1969) is that they represent average conditions and cannot reflect either the lower or higher costs that may be associated with geologic conditions that differ from the average. All new mining ventures attempt to use the highest grade deposits and the most favorable geologic conditions first in order to make the economics of the first plants more favorable. It has been suggested that if conditions particularly favorable to open pit mining could be found for the thick deposits that contain good quality shale that much lower costs than those indicated above might be attainable. Mining capital and operating costs for case 1 represent about \$1.25 per barrel of a total cost of about \$4.00. Thus, material reduction of the mining cost, for example, by 50 percent would have an important and possibly controlling impact on the economics of shale oil production. If thick beds of shale that outcropped at the surface could be located, so that very small head-end costs (requiring little overburden to be removed) before commercial production of oil shale were possible, mining cost reductions of the order mentioned may be attainable.

As mentioned above, other technology about which the Department of the Interior had insufficient information to make cost estimates similar to those made for the gas combustion retort tested by the Bureau of Mines might indicate production of shale oil at costs lower than those shown. The absence of commercial developments on privately-owned land, combined with the weak bids received on the three tracts offered by the Department in December of 1968, would appear to indicate that this other technology is probably not much more advanced than the marginal technology of the gas combustion retort.

Finally, in using these cost estimates it should be remembered that, while they are believed to be accurate within ± 10 percent, there is no certainty that they are this accurate. Even a ± 10 percent error introduces a possible ± 40 cents per barrel error which would represent a change in the D.C.F. from 9 percent to over 15 percent for case 1. Obviously, the variations of a cost engineering estimate for a non-existent technology might be even greater, and could make the difference between a very profitable or a very marginal operation.

VI. Conclusions

In the past two years additional and promising information has been developed with respect to the in situ (nuclear and non-nuclear) retorting of oil shale. In non-nuclear in situ retorting, methods to increase appreciably the permeability of the oil shale have been demonstrated. Also proven in a retorting experiment were (1) a combustion zone can be established in fracturing oil shale, (2) this zone can be moved through shale by air injection, (3) permeability does not decrease during retorting (at the shallow depths tested), and (4) recovery of the shale oil presents no special problems.

In nuclear in situ retorting, the above-ground processing of a simulated nuclear chimney indicated that under these conditions good control of the combustion front could be achieved and that even the largest pieces of oil shale could be retorted satisfactorily. No other new experimental data have been published during the past two years to establish the feasibility of the nuclear in situ retorting process.

Earlier cost estimates of both nuclear and non-nuclear in situ retorting were based on the assumptions that the new experiments performed in the past two years would be successful. As a result, it was unnecessary to recalculate these estimates. As a result of increased capital costs the most favorable in situ case showed an increase of 45 cents per barrel between 1966 and 1969, but remained in the competitive range with above-ground retorting.

The situation with respect to above-ground retorting indicates that, for the four cases which were recalculated, although a number of changes in the assumptions must be made to reflect 1969 conditions, shale oil remains marginally competitive as it did in 1966. This, however, does not consider the availability of any greatly improved proprietary technology for either mining or retorting or the use of a lease with very favorable geologic conditions. For any of these conditions, or combinations of them, a first commercial oil shale plant may look very financially attractive.

Table 1

Energy Consumption by Sector, 1968 and 2000
Trillions of BTU

	<u>1968</u>	<u>2000</u>
Residential and Commercial	13,599	21,066
Industrial	19,348	32,594
Transportation	15,136	36,600
Electricity Generation	14,046	72,291
Miscellaneous and Unaccounted for	<u>295</u>	<u>-----</u>
Bureau of Mines (1969) Estimate	62,424	162,551
Estimate Made in "Energy R & D and National Progress" (1963)		135,000
Estimate Made by Batelle Northwest (1969)		170,000

Table 2 - Operating Cost of Oil-Shale Processing Alternatives 1/

MINING OPTIONS	RETORTING OPTIONS			
	First generation 1972		Improved first generation, 1976	
	7, 45-ft- diam units ^{3/} /	Operation 10% above design	7, 60-ft- diam units ^{4/} /	28, 60-ft- diam units ^{5/} /
Room and pillar				
Capital investment, million \$	\$138	\$142	\$197	\$204
Annual operating cost, million \$	26.8	28.1	35.7	36.3
Cost per barrel: <u>2/</u>				
Before by-product credit, \$	2.10	1.99	1.57	1.52
After by-product credit, \$	1.49	1.39	0.97	0.55
Improved room and pillar				
Capital investment, million \$	142	146	203	210
Annual operating cost, million \$	25.4	26.5	33.2	33.8
Cost per barrel: <u>2/</u>				
Before by-product credit, \$	1.99	1.88	1.46	1.41
After by-product credit, \$	1.38	1.28	0.85	0.44
Open pit				
Capital investment, million \$	138	141	196	204
Annual operating cost, million \$	26.6	27.8	35.3	35.9
Cost per barrel: <u>2/</u>				
Before by-product credit, \$	2.08	1.98	1.56	1.50
After by-product credit, \$	1.47	1.37	0.95	0.53
Improved open pit				
Capital investment, million \$	139	143	199	206
Annual operating cost, million \$	24.2	25.1	31.1	31.6
Cost per barrel: <u>2/</u>				
Before by-product credit, \$	1.89	1.79	1.37	1.32
After by-product credit, \$	1.28	1.18	0.76	0.35
Advanced cut and fill				
Capital investment, million \$	148	152	214	221
Annual operating cost, million \$	23.7	24.7	30.3	30.9
Cost per barrel: <u>2/</u>				
Before by-product credit, \$	1.86	1.75	1.33	1.29
After by-product credit, \$	1.25	1.15	0.72	0.32

1/ Capital investment includes working capital and operating cost includes depreciation, but no allowance is made for Federal income tax, cost of capital, or return on investment (Note difference in Table 3)

2/ Cost per barrel is in terms of semi-refined shale oil and 1966 dollars

3/ 35,020 barrels per day

4/ 62,265 barrels per day

5/ 65,540 barrels per day

Table 3 - Summary Statistics 1/

	Case 1 First generation retort room and pillar mine		Case 2 Improved first gen- eration retort, impr. room and pillar mine		Case 3 Improved first gen- eration retort, impr. open mine		Case 4 Second generation retort, cut and fill mine	
	1966	1969	1966	1969	1966	1969	1966	1969
Size of plant: Semi-refined oil, barrels-per-day Shale for 20 years, million tons		35,020 440		62,265 780		62,265 780	65,540 780	
A. Capital investment, millions of dollars	138	152	203	223	199	218	221	240
B. Operating cost, millions of dollars	18.4	23.0	21.7	24.4	20.0	22.6	17.1	20.8
C. Market value of product, dollars: Semi-refined oil, per barrel By-products, per barrel Total, per barrel	3.08 .61 3.69	3.33 .41 3.74	3.08 .61 3.69	3.33 .41 3.74	3.08 .61 3.69	3.33 .41 3.74	3.08 .97 4.05	3.33 .77 4.10
D. At 12% discount rate, dollars: Cost of shale oil and by-product at zero resource value, per barrel	3.59	3.97	2.73	2.88	2.61	2.73	2.55	2.88
E. Discount rate at which resource has zero value when products have 1966 market value, percent	13	9	19	16	20	17	22	20

1/ Operating cost includes depreciation and excludes profit (Note difference in Table 2)

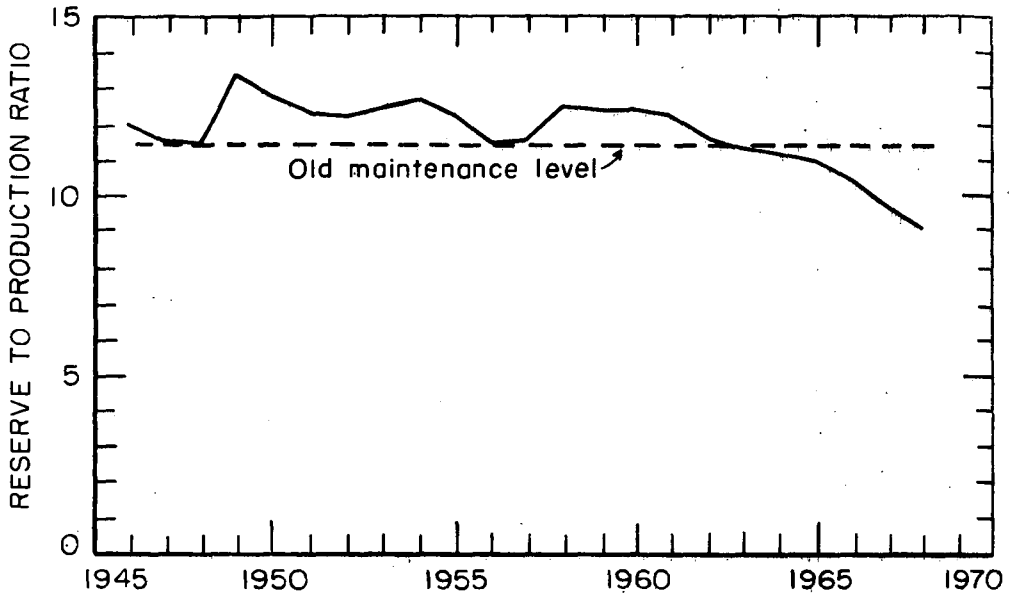


Figure 1 - Trends in the reserve to production ratio 1945-1968

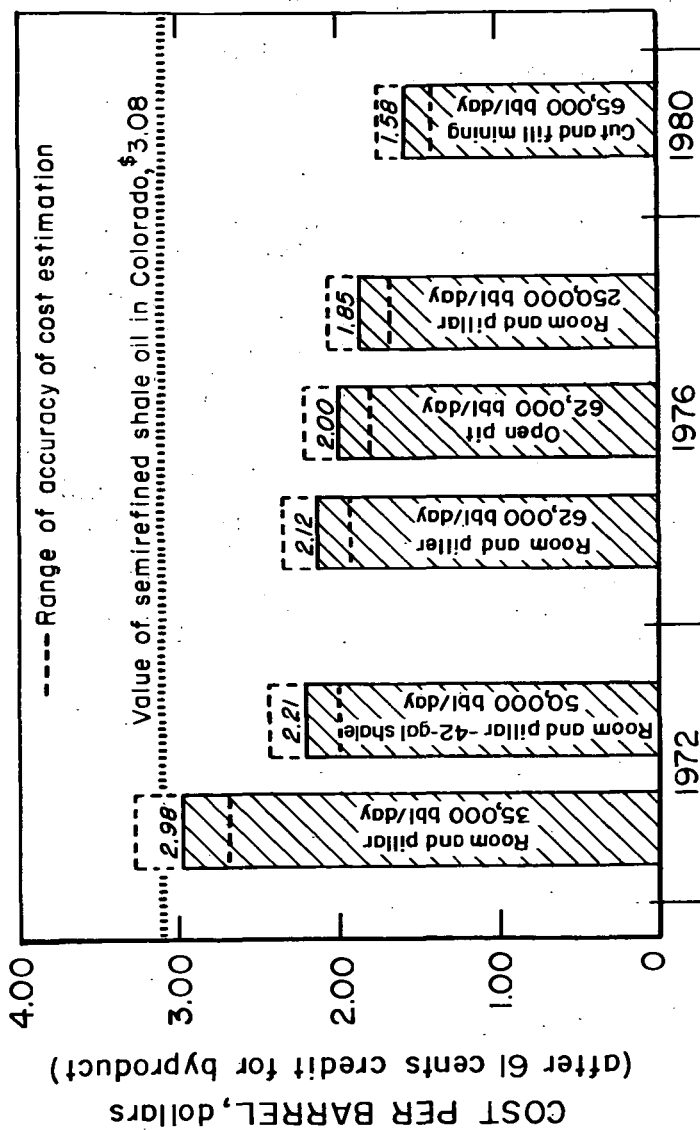


Figure 2 - Cost of shale oil at zero resource value using aboveground gas combustion retorting (12 percent discounted cash flow) 30 gallon shale (unless noted)

L-11576